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Illinois Power EXHIBIT NO. 2.8
WITNESS Leonard M. Jones & Mark J. Peters
DATE 10-2-00 REPORTER CB

ILLINOIS COMMERCE COMMISSION

DOCKET NOS. 00-0259, 00-0395, 00-0461 (Cons.)

PREPARED SURREBUTTAL TESTIMONY OF

LEONARD M. JONES & MARK J. PETERS

SEPTEMBER 22, 2000

1. Q. Please state your name, business address and present position.

A. (Mr. Jones) Leonard M. Jones, Manager of Business Planning and Forecasting, Illinois Power Company ("Illinois Power", "IP", or the "Company"), 500 South 27th Street, Decatur, Illinois, 62521.

(Mr. Peters) Mr. Mark J. Peters, Control Area Resource Manager, Illinois Power Company, 500 South 27th Street, Decatur, Illinois 62521.

2. Q. Have you previously submitted testimony in this proceeding?

A. Yes, Direct (IP Exhibits 2.1-2.5) and rebuttal (IP Exhibits 2.6-2.7) testimony.

3. Q. What additional evidence are you submitting at this time?

A. We are submitting IP Exhibit 2.8 as our prepared surrebuttal testimony containing questions and answers numbered 1 through 13.

4. Q. Do you have any concerns with statements made by NewEnergy in support of the inclusion of imbalance charges in the calculation of MVI?

A. Yes. The statement made by CILCO Witness Munson, which NewEnergy is supporting here, that "imbalance costs are real costs which are not accounted for in a published index" is simply misleading. Imbalance, pure and simple is the difference between a scheduled load and actual consumption. Imbalance may exist as both a charge when load has been underscheduled and as a credit when load is overscheduled. To the extent that the MVI already accounts for load uncertainty in its pricing, as presented by ComEd witness Huntowski (at page 13 of his rebuttal), imbalance is already accounted for.

TC's are calculated off of the customer's historical usage and not the schedules which an ARES submits for serving the load. It would be entirely inappropriate to apply an imbalance adjustment based on an individual customer's actual imbalance without simultaneously changing the basis for calculating the TC from the profiled/historical load shape to the schedules which were the basis of the imbalance. To do otherwise would seriously distort the economic basis of the TC calculation and potentially reward those who schedule the worst and through their actions imperil system reliability. An example of this would be an ARES who grossly underschedules a customer's load in every hour of the year by scheduling in a 100% load factor block at the customer's minimum demand. They would indeed incur a substantial cost for imbalance, to account for the fact that they failed to purchase sufficient resources to serve the load they committed to serve – but they never incurred anywhere near the base MVI cost to secure what load they did deliver. Using the MVI example from IP's filed exhibits, the commodity component cost of securing a 100% load factor block would be $0.03318, whereas a profile 407 (50.2% load factor) customer would have an MVI of $0.0427.

If the imbalance cost associated with the gross underscheduling was allowed to be added to the profile based market value (which reflects load uncertainty and load following through load-weighting and price shaping), rather than to the 100% load factor cost basis suggested by the schedule which created the imbalance, there would be an embedded 9.1 mil error in the MVI.

5. Q. Do you have any comment on NewEnergy's continued criticism of the use of the Into Cinergy methodology by Illinois Power?

A. Yes. As previously stated, there is no viable Into Illinois Power hub that we are aware of. As such, the use of any other location as the source data will require a basis adjustment. We agree with Staff Witness Zuraski that the Into Cinergy represents an adequate representation of prices for Illinois Power once a basis differential is applied. We believe that the studies presented by Staff Witnesses Zuraski and Christ support the close relationship of prices between Cinergy and Illinois Power and support Mr. Christ's conclusion that our proposed multiplicative adjustment is a better method for handling this basis differential.

While NewEnergy has questioned the use of Into Cinergy for use by Illinois Power, we cannot find where they have proferred any alternative other than Into ComEd. We object, however, to being forced to use an index whose depth and veracity are being questioned to a much greater degree by others in this proceeding. It appears that, by challenging the use of basis differentials in general, NewEnergy is suggesting that the only valid index is Into ComEd, and then only for ComEd, thereby leaving the balance of the state without a viable alternative to the NFF. We find this concept to be untenable.

6. Q. Is Illinois Power willing to change its hierarchy in regard to the inclusion of bid/offer data for contracts in which actual trades occur?

A. Yes, if sufficient evidence exists that such a change is actively supported by Staff, the various ARES and a significant number of customers. The proposed methodology was developed in light of significant debate and concern regarding the inclusion of bid/offer data in the index calculation and was intended to minimize the impact of these unexecuted values. We agree that the methodology as proposed could allow a single transaction to override other bid/offer representations that may have existed, but reiterate that as an executed transaction, it clearly demonstrates a level at which agreement was reached on value, whereas the bid/offer represents a range in which one would expect to see eventual agreement.

Given the expressed concerns of many in this proceeding, and the testimony of Staff in regard to the manner in which bids and offers were developed for ComEd's initial, Into ComEd-based MVI, IP understands the concerns of utilizing bid/offer data in the Into ComEd market. Since IP is not willing to modify its proposal to change from an Into Cinergy to an Into ComEd index, we believe, as NewEnergy has suggested (at p. 8 of its rebuttal), that this would be of less concern for our proposal.

7. Q. Do you have any comment in regard to NewEnergy's continued assertion (at rebuttal, p. 9) that the MVI as proposed by Illinois Power does not adequately represent the value of the "freed-up firm electric power and energy the utility can sell over the minimum one-month switch period".

A. Yes. We find it misleading when NewEnergy, among others, appears to argue that for every megawatt of load which leaves the host utility, the utility has an another megawatt to sell as firm in the open market. This assertion fails to take into account several points:

1) Not every MW that leaves is firm. A significant portion of the load currently on Delivery Services is non-firm.
2) Unlike an ARES who has the luxury of picking and choosing its customers, Illinois Power is required by statute to accept all customers who choose to take service from them, without regard to notice periods, available supply resources or the demand requirements of the customer. The provider of last resort requirement imposed upon Illinois Power as provider of both imbalance service and what has been termed as no-fault default service, requires that Illinois Power maintain sufficient reserves to meet these potential needs, whenever they may occur. As such, for every MW that takes alternate choice, the Company may not have a full MW available to sell.
3) While the MW which is freed up was being used to serve a full requirements customer in every hour in which that customer consumed energy, it is not clear that, when that supply is provided by a third party, there is adequate

demand remaining to allow the utility to sell the "freed up power and energy" to another customer – wholesale or retail

NewEnergy and others have argued that one must look at the actual product being purchased by retail customers, rather than a suitable representation of the value of power and energy in the region. Using similar logic, the value to Illinois Power of the freed up MW may be substantially different (and likely lower) than the MVI. The statute does not say that only one participant's value shall set the market. Rather it refers to the mutual market in which both utilities and customers operate. To argue for a multitude of upward adjustments due to supposed additional costs borne by customers, without making similar, offsetting downward adjustments to reflect reduced value for the utility is inappropriate.

8. Q. Does IP agree with ComEd witness Huntowski's testimony in regard to the off-peak component of the MVI?

A. Yes. IP agrees that forward prices would be preferrable to historical prices in the development of off-peak prices, but that forward off-peak or around-the-clock prices are not readily available. We support the concept that historical off-peak prices are a suitable proxy for these prices given their relative stability over time.

We are also pleased to see that Mr. Huntowski has presented a rebuttal to NewEnergy's contention that the use of historical data tends to bias the MVI downwards, which is similar in many respects to the rebuttal to this issue which IP itself has presented. In particular, IP could not agree more wholeheartedly, with his statement (at p. 12) "If buyers knew that generators were going to dump power at cheap prices, then why would they agree to buy power at very high prices on a forward basis?"

9. Q. Mr. Peters, do you specifically, support ComEd witness Naumann's rebuttal of NewEnergy's characterization of "good faith scheduling"?

A. Yes. In addition to those current responsibilities identified in my previous testimony, I am also responsible for the forecasting and scheduling of customer's PPO loads as their transmission service agent. It has been my experience in performing these duties, that 1) ComEd's business practices are consistent with what Mr. Naumann has presented, and 2) that Illinois Power's transmission service's business practices are also consistent with those presented for ComEd by Mr. Naumann. It is my understanding that a good faith hourly schedule does not require hourly, real time updates and that block scheduling – particularly an "Aztec pyramid" or "wedding cake" – is permitted. More significantly, I am unaware of any requirement that an ARES supply a customer with only native load firm or load following service across network designated service. ARES are free to obtain point-to-point transmission service both firm and non-firm or network undesignated service in addition to network designated service. While an ARES must demonstrate that it has a real network resource available to it to secure network designated service, it may freely "build a supply portfolio to meet its schedule in any way that it sees fit, including purchases and sales of standard wholesale products," as Mr. Naumann notes at p. 7.

While this may present certain risks to the ARES, it also provides an opportunity to secure resources at prices well below that used in the calculation of the MVI – even when combined with whatever designated network resource costs they may have incurred if they chose to obtain network designated transmission service. It is this concept of risk transfer and various risk appetites, which makes for a robust, active market.

10. Q. Has NewEnergy misstated Illinois Power's transmission service requirements?

A. Yes. NewEnergy is supporting an incorrect assertion made by CILCO witness Munson. Illinois Power does not require a 15% planning reserve margin and therefore there is no basis for the adjustment NewEnergy is supporting.

11. Q. Do you have additional reasons to support your conclusion that CILCO is incorrect?

A. Yes. Illinois Power's proposal for calculating non-firm MVI values includes a 15% reduction from the Firm price. The reason for this is that the firm price already contains a component for short term planning reserves. Although CILCO has yet to change its conclusion, it has in fact recognized the validity of IP's position in response to IP's first set of data requests. CILCO quotes our direct testimony on the Non-Firm adjustment and goes on to state that "IP recognizes the fact that to serve a customer with Firm Energy a RES must secure and pay for an additional 15% to cover for reserves. This is an additional cost to serve customers in IP's territory and should be accounted for by increasing the market value in IP's territory." However, the price of Firm Energy is already reflective of a reserve/capacity component, which is the basis of our proposal to remove this reserve/capacity component to calculate the value of Non-Firm energy. CILCO is really recommending that this value be counted for twice.

12. Q. Does IP agree with Ameren witness Hock's characterization of IP's proposed method of calculating a separate annual TC for each of the 12 anniversary months?

A. No. While we agree with his statements that a given method is preferred by a given utility and may suit them best for a variety of reasons, we do not concur with the conclusions he has reached in comparing the A/B method with the 12 month method.

First, there is obviously a substantial number of customers in Illinois who have yet to exercise choice. For those desiring a one year contract from a supplier, whether that be through an ARES or the PPO, the only means those customers have under Method A/B of securing a 12 month certain TC on their initial enrollment is to take choice in June. (Certainty here is discussed only in regard to the commodity portion and assumes that the base T&D rates remain unchanged.) For all other customers they must either limit the length of their initial contract or sign a one year contract without certainty of TC's for the latter portion of the contract. Either presents a risk to the customer. A customer electing choice in September who limits its contract length (either by choice or by lack of offers from ARES) faces a risk that there will not be any competitive offers the next summer and will be forced to take service either through the PPO or the utility's bundled service – either of which represents a one year commitment. If the same customer instead enters into a one year contract, it does so without knowing its TC for the last three months of the contract. Under IP's proposal, the customer receives 12 month certainty of its TC, regardless of the month in which it chooses to enroll.

Second, while much has been said by both Ameren and ComEd about the A/B method being calculated closer to the summer, which we agree is the most volatile time period, IP finds this argument to have little significance. It is not the proximity to summer which matters, but rather the proximity of the calculation date to the effective period of the resultant TC which is truly important. IP has consistently argued that when the date of TC calculation is separated from the date at which the TC becomes effective, issues of "free options" and gaming opportunities become significant. IP's proposal is superior to the A/B method in this regard.

IP calculates each and every period's TC closer to the effective date of the TC than the A/B method would. IP's average delay from the last date of data capture to effective date is 39 days – every month. The A/B method has an average delay from the last date of data collection to effective date of the TC of 116.5 days for the A period and an astounding 207 days for period B. The *shortest* lag for Period A is 71 days, while the *longest* delay under the 12 month methodology for the same period is only 54 days. While we agree that a customer electing choice in September under the IP proposal has a TC based on

July/August values which are 11 and 12 months in the future, the risk of the uncertainty falls primarily on those best able to hedge it – the utility and the ARES. Since the July/August component is based off of then current values either party can use the forward financial markets to capture the current price and mitigate the risk of price movement. To say this otherwise - since the effective date of the TC is closer to the calculation date than under the A/B method in *any* month, it is more likely that the parties can buy or sell the underlying contracts as a hedge at the time of customer choice, at the same rates which were used in the calculation.

Third, the 12 month method maintains the integrity of the TC calculation for all customers. For those exercising choice under the Period B, they are billed using the stub TC which cannot be calculated within the context of the statute without unduly biasing the TC upwards (we leave for legal briefing whether any stub TC calculation can be performed under the statute). TC's are required to be calculated by using average, annual values for load and base revenue. Virtually all base rates used to calculate TC's in Illinois have a summer rate higher than the non-summer rate. Period B does not include market values for the highest cost, summer months. When an average annual base rate forms the basis of a TC calculation which utilizes a market value component which excludes values for the summer period, TC's are overstated. To avoid overstating TC's, the summer month's values in the base rate must be excluded from the calculation. Our understanding is that these values cannot be excluded from the calculation. As such, it appears that Period B requires the use of a base rate component which is higher that the customer's actual average rate for the period for which B is calculated – thereby necessarily biasing the TC for a Period B customer upwards. The following is a very simple example of the impact of including the annual average base rate in Period B vs. the Period B only average base rate. It is clear that including the higher summer values in the calculation increases the resulting TC's.

Customer Base Rate

	Kwh's	$/Kwh	
Jan	100	$ 0.050	$ 0.050
Feb	100	$ 0.050	$ 0.050
Mar	100	$ 0.050	$ 0.050
Apr	100	$ 0.050	$ 0.050
May	100	$ 0.050	$ 0.050
Jun	100	$ 0.075	
Jul	100	$ 0.075	
Aug	100	$ 0.075	
Sep	100	$ 0.075	$ 0.075
Oct	100	$ 0.050	$ 0.050
Nov	100	$ 0.050	$ 0.050
Dec	100	$ 0.050	$ 0.050
Annual Annual		**$ 0.058**	
Stub Period B Average			**$ 0.053**

TC Calculation

	Annual	Period B
Base Rate	**$ 0.058**	**$ 0.053**
Market Value	$ 0.040	$ 0.040
T&D	$ 0.008	$ 0.008
Mitigation	$ 0.005	$ 0.005
Transition Charge	$ 0.005	$ -

While Illinois Power continues to maintain that its 12 month methodology is preferable for the reasons stated above and elsewhere in our testimony, we have not advocated forced uniformity on this issue, nor have we changed our position on this matter.

13. Q. Does this concluded your prepared surrebuttal testimony?

A. Yes, it does.